Basin Margin Mesaverde Oil Play
(USGS 2210)

General Characteristics

The Basin Margin Mesaverde Oil Play is a confirmed oil play around the margins of the central San Juan Basin. Except for the Red Mesa field on the Four Corners platform, field sizes are very small. The play depends on intertonguing of porous marine sandstone at the base of the Upper Cretaceous Point Lookout Sandstone with the organic-rich upper Mancos Shale.

Reservoirs: Porous and permeable marine sandstone beds of the basal Point Lookout Sandstone provide the principal reservoirs. The thickness of this interval and of the beds themselves may be controlled to some extent by underlying structures oriented in a northwesterly direction.

Source rocks: The upper Mancos Shale intertongues with the basal Point Lookout Sandstone and has been positively correlated with oil produced from this interval. API gravity of Mesaverde oil ranges from 37° to 50°.

Timing: Around the margin of the San Juan Basin, the upper Mancos Shale entered the thermal zone of oil generation during the Oligocene.

Traps: Structural or combination traps account for most of oil production from the Mesaverde. Seals are typically provided by marine shale, but paludal sediments, or even coal of the Menefee Formation may also act as the seal.

Exploration status and resource potential: The first oil-producing area in the State of New Mexico, the Seven Lakes Field, was discovered by accident in 1911 when a well being drilled for water produced oil from the Menefee Formation at a depth of approximately 350 ft. The only significant Mesaverde oil field , Red Mesa, was discovered in 1924.

The Basin Margin Mesaverde Oil Play in Southern Ute Indian Reservation

The Cliff House and Point Lookout Sandstones are the producers in the Basin Margin Mesaverde Oil Play in the Southern Ute Indian Reservation (Fig. SU-37). The Point Lookout shoreface prograded in a staircase fashion across the basin, as a series of steps and risers until it reached its seaward depositional limit (Fig. SU-36). At this limit, there is a change in the stacking pattern of genetic sequences from seaward-stepping to landward-stepping. This marks the beginning of the Cliff House shoreface aggradation (Fig. SU-36). Reservoir-quality sandstones in the two vertically stacked shorefaces at the turn-around position are 70 m thick.

The Point Lookout Sandstone is the most extensive regressive marine Cretaceous sandstone in the San Juan Basin. Formed during shoreline regression, it covers virtually the entire basin. Its shoreline trended northwest-southeast and prograded toward the northeast in a series of thick, imbricated, sandstone units. Straight, wave dominated shoreface and delta-front deposits form the bulk of the sandstone; tidal, foreshore, and offshore sandstones are lesser constituents. Cores 1HCMS and 2 HCMS (Figs. SU-38 thru 40) show fluvial/estuarine, shoreface, and delta-front deposits of the Point Lookout Sandstone. The best reservoir sandstones, in terms of porosity and permeability, are found in zones in the upper and lower shoreface environments and the shoreface/delta front environments. These sandstones are least influenced by carbonate cementation, and appear least sensitive to increased confining stress. Reservoir characteristics of the Point Lookout show that the sandstones are conventional rather than tight. Measured porosity in the 1HCMS well range from 4.2-20.5 percent and 6.6-20.4 percent in the 2HCMS well. Measured ambient permeabilities are 0.0003-56.3 md for the 1HCMS well and 0.0007 to 59.3 md in the 2HCMS well. Higher permeabilities are more common in the upper shoreface and shoreface/delta-front depositional environments. Diagenesis also influence reservoir quality. The highest amounts of carbonate cement are generally in the lower to middle shoreface environment. There is a general increase in carbonate cement directly above and below many of the shale breaks.

The Cliff House Sandstone consists of several linear sandstone complexes (Fig. SU-36). The thicker parts are connected by thin sandstone sheets; where these sheets are absent, the Lewis Shale rests directly on the Menefee Formation. The depositional environments present in the Cliff House Sandstone are fluvial/estuarine, shoreface, and delta front. The Cliff House Sandstone benches are composed of homogeneous, mud-free sandstone dominated by amalgamated hummocky and swaley cross stratification.)

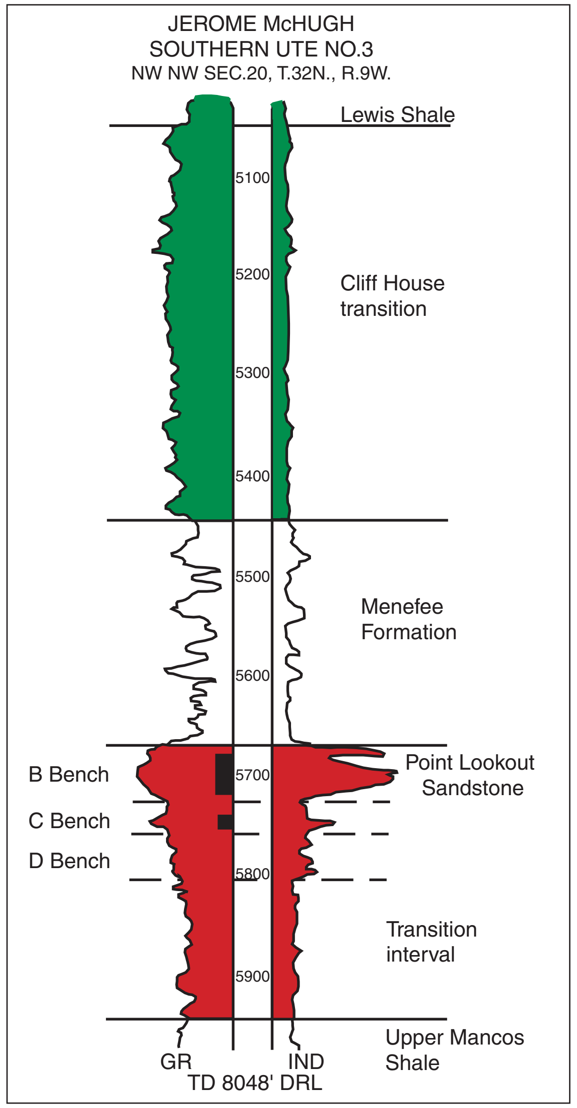

Figure SU-37. Log of the Mesaverde pool stratigraphic units showing perforated and producing "B" bench reservoir of the Point Lookout Sandstone. The "A" bench is absent by non-deposition and the "C" and "D" benches are shaley. Well is the Jerome McHugh Southern Ute No. 3, NW, NW, sec. 20, T32N, R9W, La Plata Co., CO (modified after Keighin, et al., 1993).

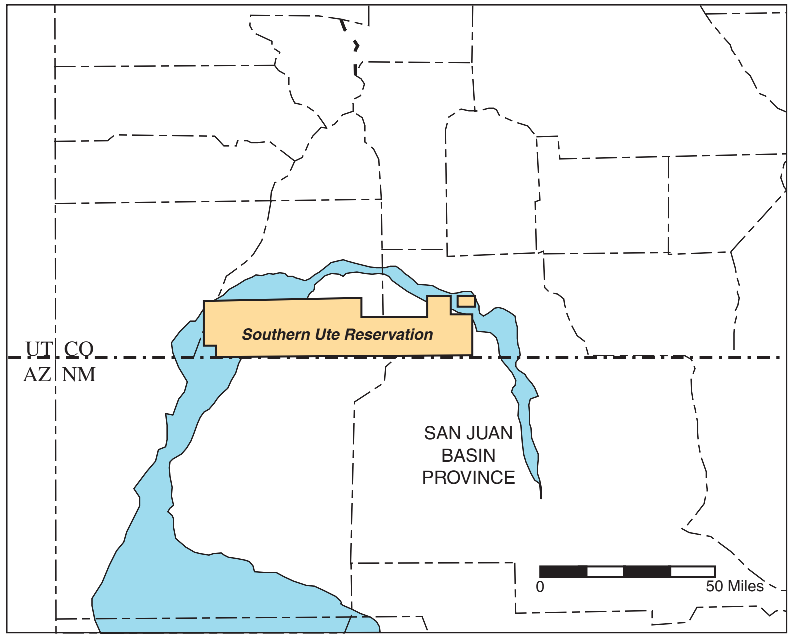

Figure SU-35. Location of the Basin Margin Mesaverde Oil Play (modified after Gautier, et al., 1996).

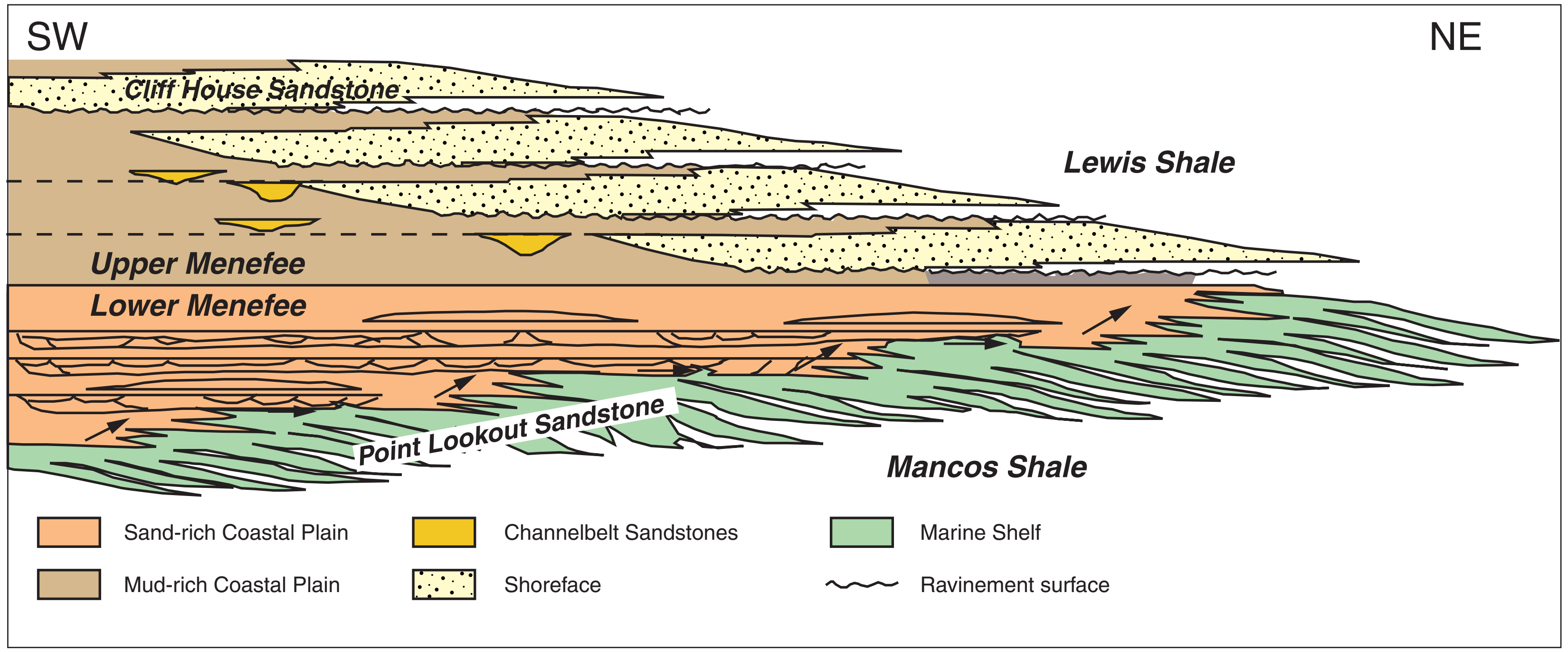

Figure SU-36. Diagram of the stacking patterns of genetic sequences in the Mesaverde Group, and the temporal relations among the five formations that encompass them (modified after Cross and Lessenger, 1997).

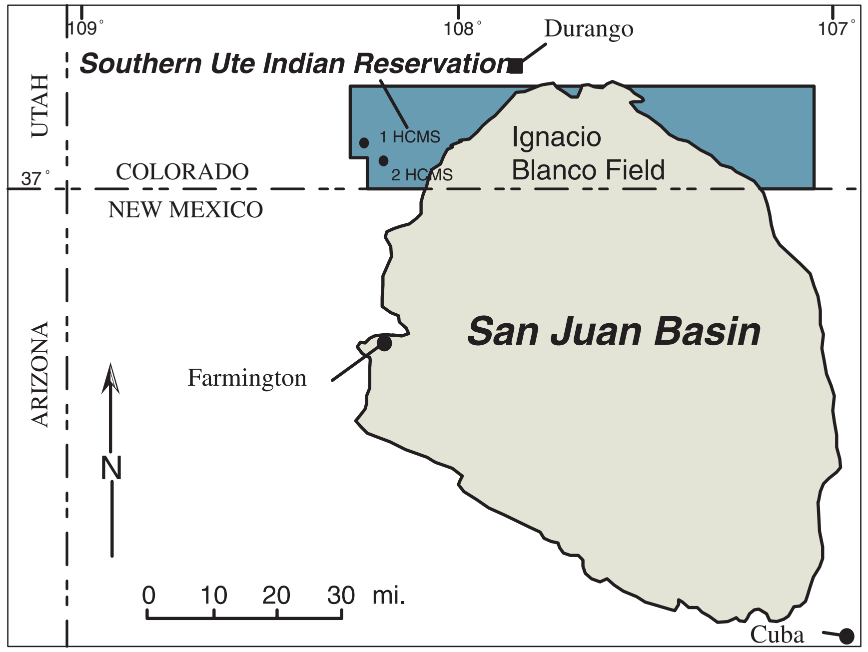

Figure SU-38. Index map showing location of the San Juan Basin as defined by the Fruitland-Pictured Cliffs contact, Ignacio-Blanco gas field, Southern Ute Indian Reservation, and drill holes 1HCMS (sec 30, T33N, R13W) and 2HCMS (sec 5, T32N, R13W) (modified after Keighin, et al., 1993).

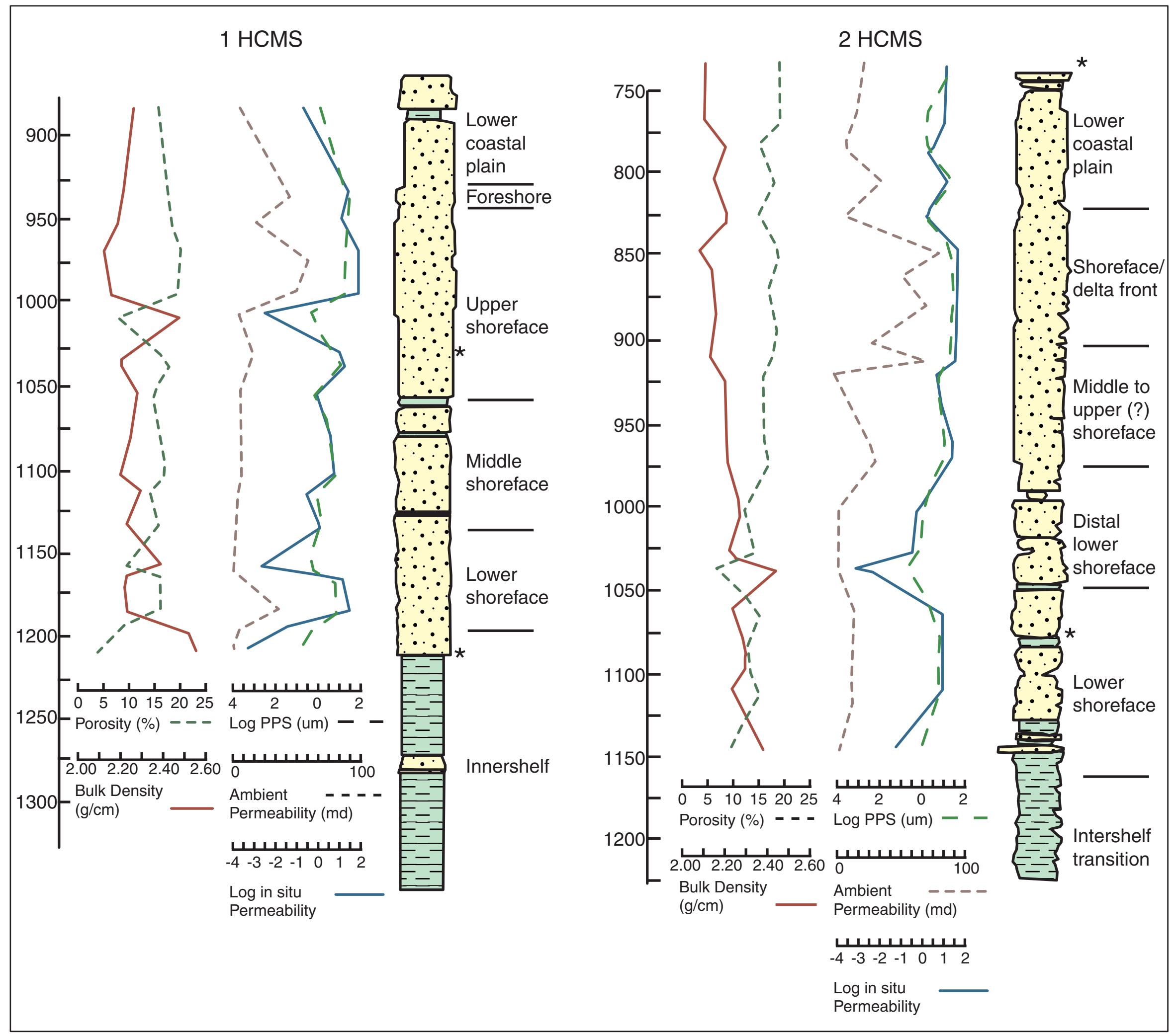

Figure SU-39. Relationship in the Point Lookout Sandstone between measured porosity, bulk density, ambient and in-situ permeability, calculated principle pore size (PPS), observed lithology of cores, and interpreted depositional environments (modified after Keighin, et al., 1993).

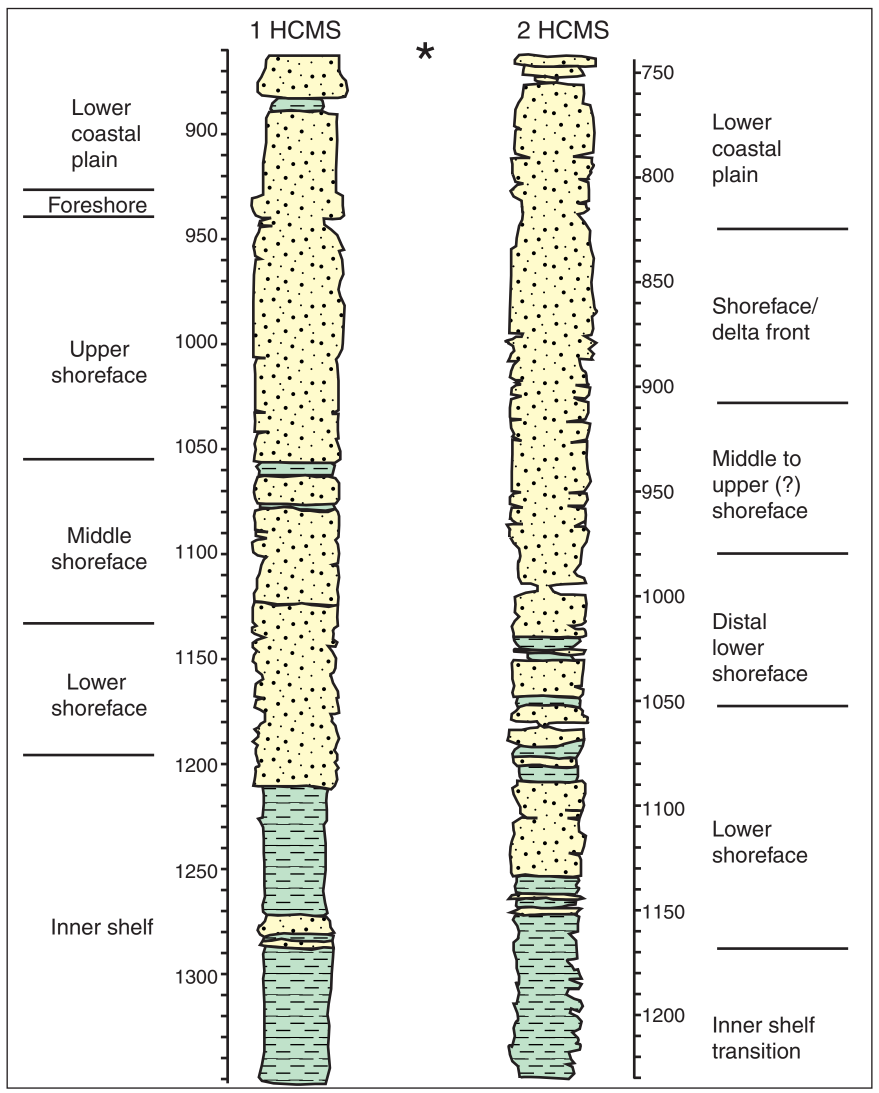

Figure SU-40. Comparison of depositional facies in the Point Lookout Sandstone, as determined from cores; for core holes 1HCMS and 2HCMS (modified after Keighin, et al., 1993).

Analog Fields In and Near Reservation

The Basin Margin Mesaverde Oil Play only produces from one field in or near the Southern Ute Indian Reservation. That field is the Red Mesa field. Figure SU-41 is a location map of the field. There is no data available for Mesaverde production, oil characteristics, reservoir quality, etc. in the Red Mesa field. The Central Basin Mesaverde Play provides additional information about Mesaverde Production in the Southern Ute Indian Reservation. (Lauth, 1983)

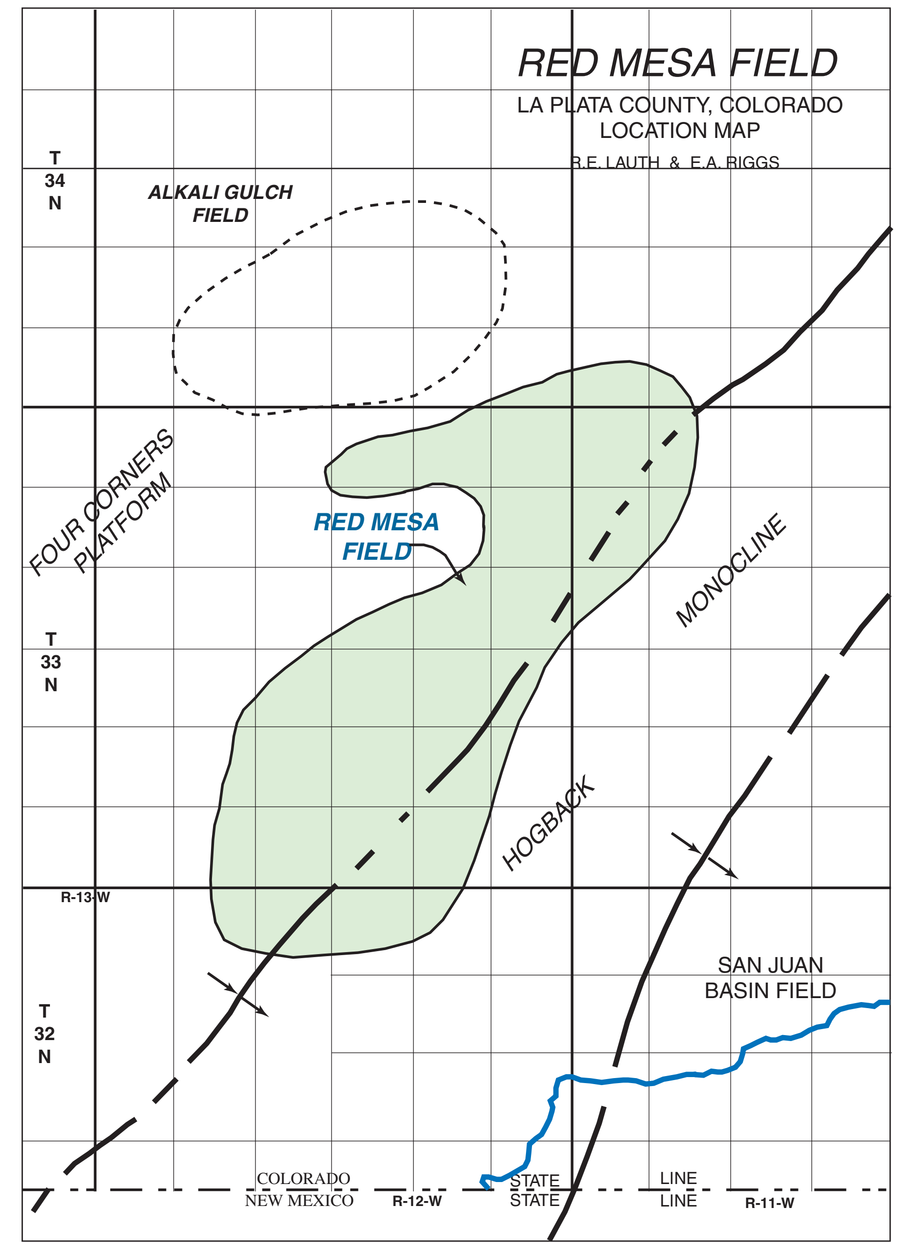

Figure SU-41. Location map of the Red Mesa Field (modified after Lauth, 1983).

Fruitland-Kirtland Fluvial Sandstone Gas Play

(USGS 2212)

General Characteristics

The Fruitland-Kirtland Fluvial Sandstone Gas Play covers the central part of the basin and is characterized by gas production from stratigraphic traps in lenticular fluvial sandstone bodies enclosed in shale source rocks and (or) coal. Production of coalbed methane from the lower part of the Fruitland has been known since the 1950's. The Upper Cretaceous Fruitland Formation and Kirtland Shale are continental deposits that have a maximum combined thickness of more than 2,000 ft. The Fruitland is composed of interbedded sandstone, siltstone, shale, carbonaceous shale, and coal. Sandstone is primarily in northerly-trending channel deposits in the lower part of the unit. The lower part of the overlying Kirtland Shale is dominantly siltstone and shale, and differs from the upper Fruitland mainly in its lack of carbonaceous shale and coal. The upper two-thirds or more of the Farmington Sandstone Member of the Kirtland Shale is composed of interbedded sandstone lenses and shale.

Reservoirs are predominantly lenticular fluvial channel sandstone bodies, most of which are considered tight gas sands. They are commonly cemented with calcite and have an average porosity of 10-18 percent and low permeability (0.1–1.0 md). Pay thickness ranges from 15 to 50 ft. The Farmington Sandstone Member is typically fine grained and has porosity of 3 to 20 percent and permeability of 0.6 to 9 md. Pay thicknesses are generally 10–20 ft.

Source rocks: The Fruitland-Kirtland interval produces nonassociated gas and very little condensate. Its chemical composition (C1/C1-5) ranges from 0.99 to 0.87 and its isotopic (d13C1) compositions range from -43.5 to -38.5 per mil (Rice et al., 1988). Source rocks are thought to be primarily organic-rich nonmarine shales encasing sandstone bodies.

Timing and migration: In the northern part of the basin, the Fruitland Formation and Kirtland Shale entered the thermal zone of oil generation during the latest Eocene and the zone of wet gas generation probably during the Oligocene. Migration of hydrocarbons updip through fluvial channel sandstone is suggested by gas production from immature reservoirs and by the areal distribution of production from the Fruitland.

Traps: The discontinuous lenticular channel sandstone bodies that form the reservoirs in both the Fruitland Formation and Kirtland Shale intertongue with overbank mudstone and shale and paludal coals and carbonaceous shale in the lower part of the Fruitland. Although some producing fields are on structures, the actual traps are predominantly stratigraphic and are at updip pinchouts of sandstone into the fine-grained sediments that form the seals. Most production is from depths of 1,500–2,700 ft. Production from the Farmington Sandstone Member is from depths of 1,100–2,300 ft.

Exploration status and resource potential: The first commercially produced gas in New Mexico was discovered in 1921 in the Farmington Sandstone Member at a depth of 900 ft in what later became part of the Aztec field. Areal field sizes range from 160 to 32,000 acres, and almost 50 percent of the fields are 1,000–3,000 acres in size. The almost linear northeasterly alignment of fields along the western side of the basin suggests a paleofluvial channel system of northeasterly flowing streams. Similar channel systems may be present in other parts of the basin and are likely to contain similar amounts of hydrocarbons. Future potential for gas is good, and undiscovered fields will probably be in the 2–5 sq mi size range at depths between 1,000 and 3,000 ft.

Because most of the large structures have probably been tested, future gas resources probably will be found in updip stratigraphic pinchout traps of channel sandstone into coal or shale in traps of moderate size (Gautier et al., 1996).

Characteristics of the Fruitland-Kirtland Fluvial Sandstone Gas Play

Many studies have focused on the Fruitland-Kirtland Fluvial Sandstone Gas Play in the past ten years (Harr, 1988; Bland, 1992; and Hoppe, 1992). For this reason, the following should be considered an extremely brief overview.

The Fruitland Formation contains up to 50 TCF of coalbed methane in place. Half of this may be producible reserves. The Fruitland pore system ranges from overpressured to underpressured. The Fruitland Formation lies stratigraphically above the Pictured Cliffs Sandstone. The Fruitland consists of sandstone, limestone, shale, carbonaceous shale, coal, and volcanic ash. It represents numerous environments on the coastal plain. Environments change quickly laterally and include stream, overbank, floodplain, swamp, and tidal deposits. Production from the Fruitland is highly dependent on finding areas where cleating is preserved or in locating natural fractures. Production is also controlled by net thickness of coals.

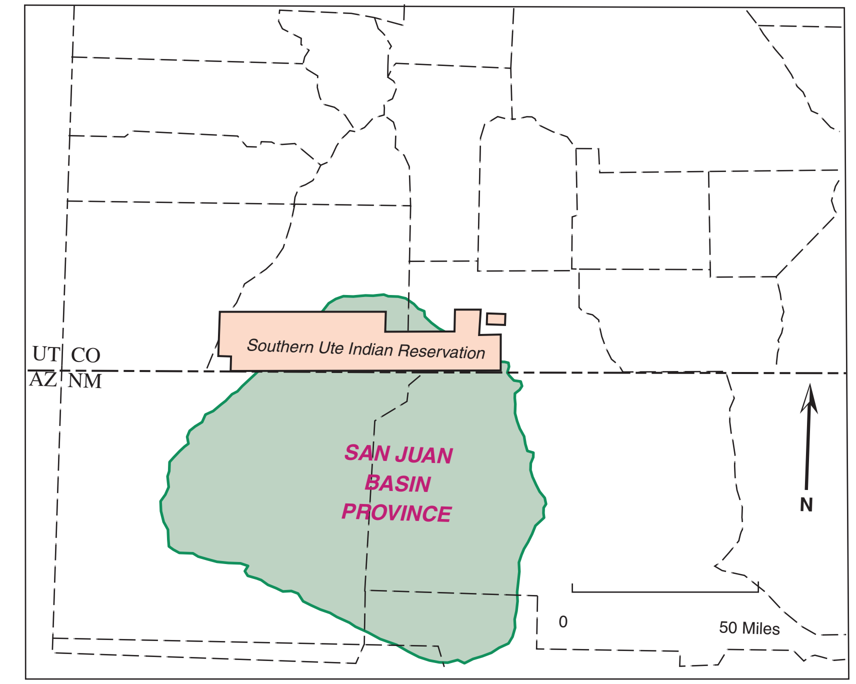

Figure SU-42. Location of the Fruitland-Kirtland Fluvial Sandstone Gas Play (modified after Gautier et al., 1996).

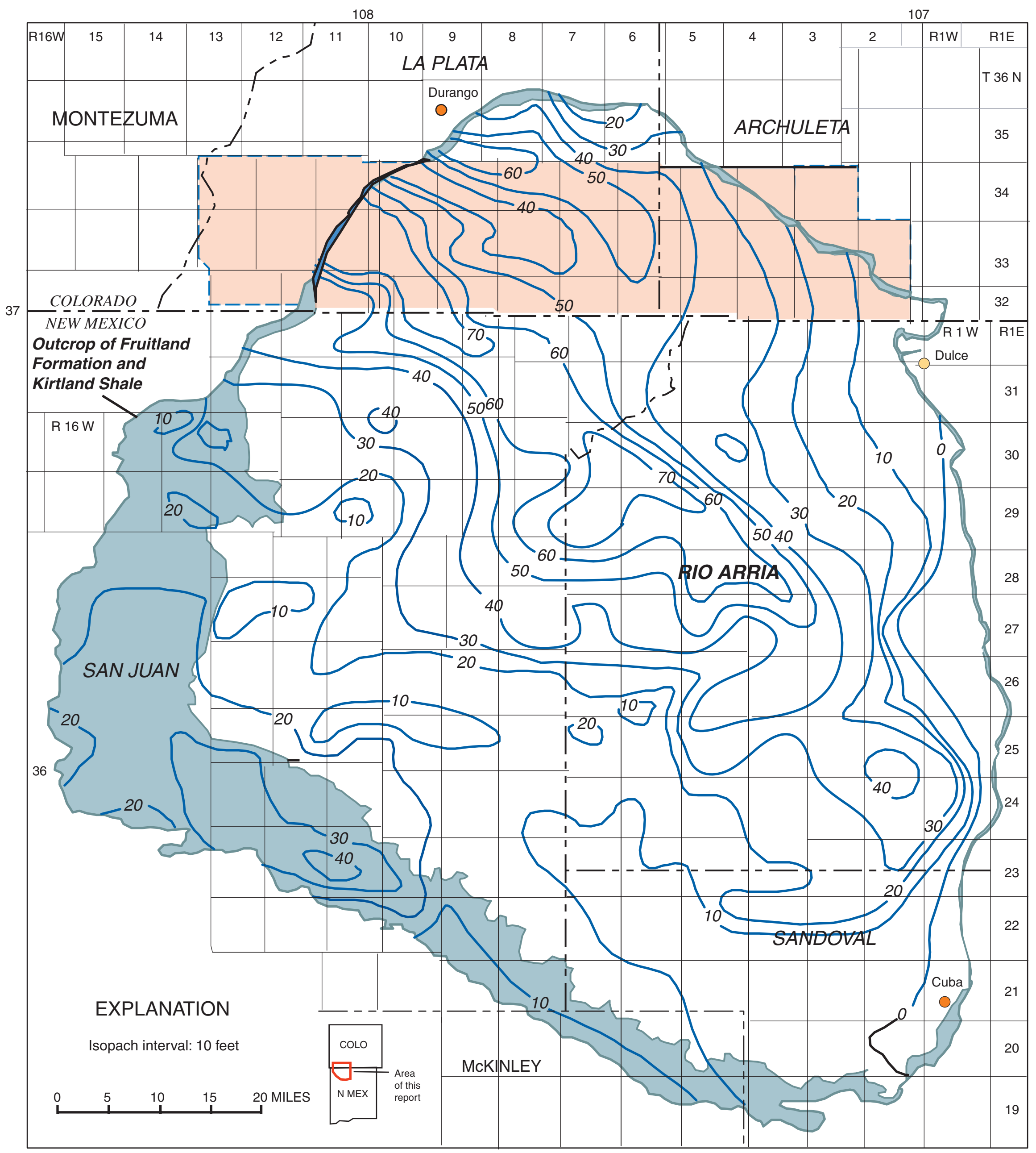

Figure SU-43. Gas-in-place contour map for the Fruitland Formation. Contour interval is 10 BCFG / mi^2. (modified after Kelso and Wicks, 1988).

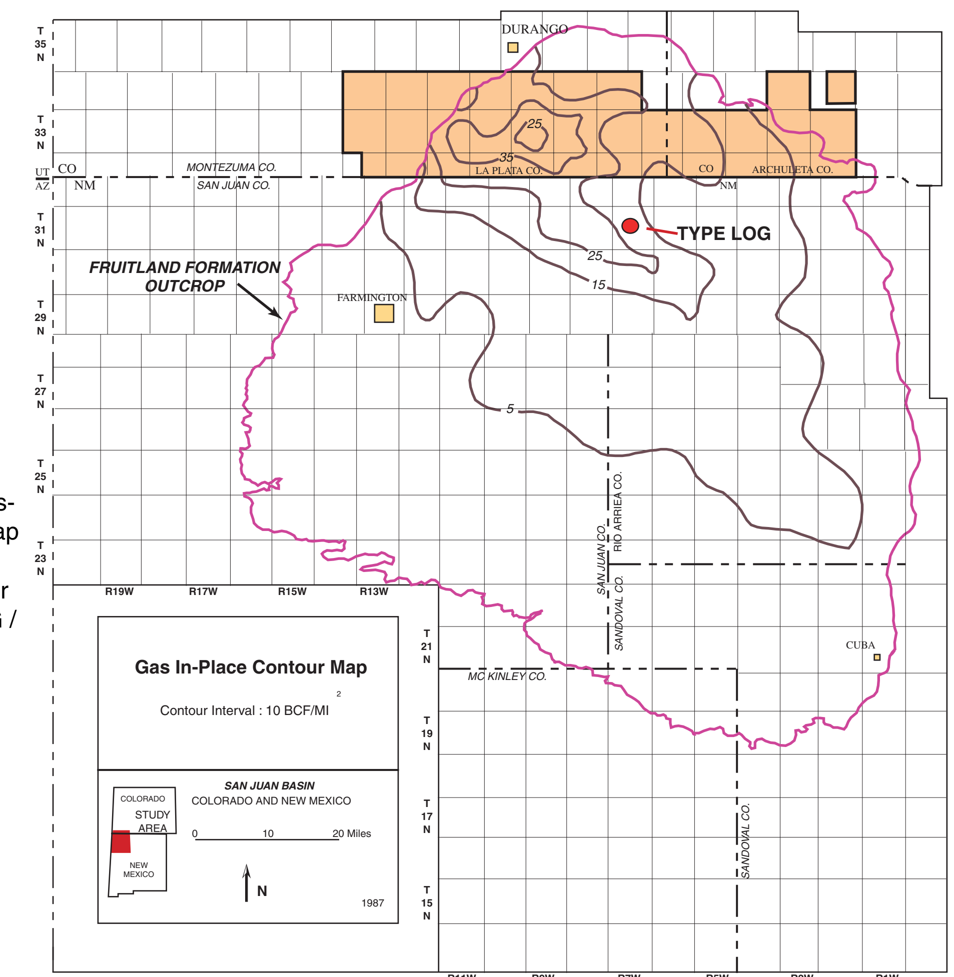

Figure SU-44. Isopach map of total thickness of coal in the Fruitland Formation. Contour interval is 10 feet (modified after Fassett, 1988).

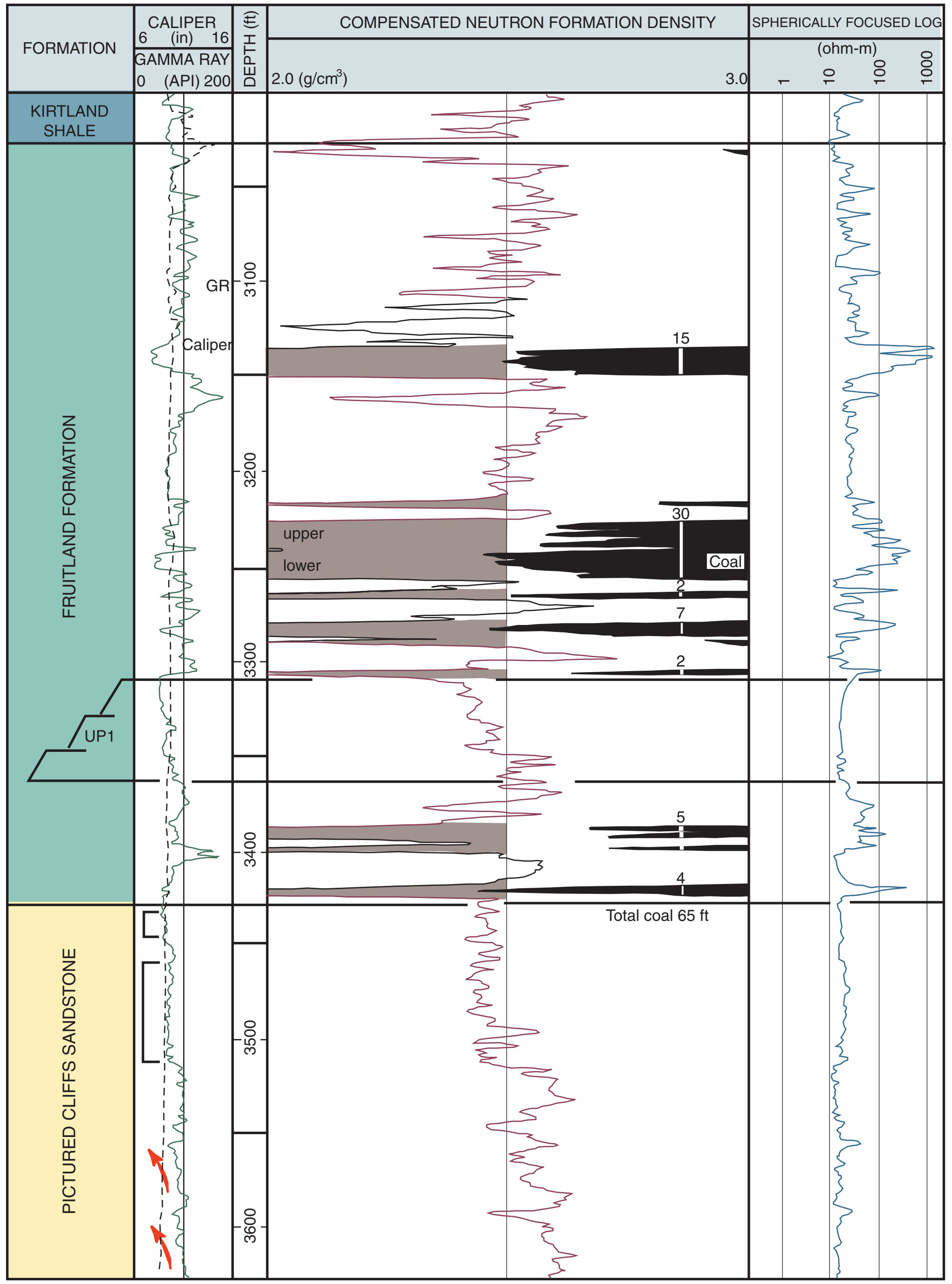

Figure SU-45. Identification and measurement of Fruitland Coal in type log (location is labeled in figure 44). High natural gamma response, indicated by arrows, are attributed to volcanic ash beds and to organically bound radioactive elements in coal seams (modified after Ayers et al., 1994).

Analog Fields In and Near Reservation

(*) denotes field lies within the reservation boundaries

*Ignacio Blanco (see Fig. SU-47)

Location of discovery well:	NE ¼, NW ¼, sec 7, T33N, R7W (1951)
Producing formation:	Cretaceous Fruitland Formation
Type of trap:	Structural / Stratigraphic
Number of producing wells:	115 (1986)
Initial Production:	2,200 MCFGD
Cumulative Production:	26,750,352 MCFG (1986)
Gas characteristics:	990 BTU
Type of drive:	Solution gas
Average net pay:	16-205 feet, 70 feet average
Porosity:	4.4%
Permeability:	0 - 1500 md

Glades Fruitland

Location of discovery well:	NW ¼, MW ¼, sec 36, T32N, R12W (1978)
Producing formation:	Cretaceous Fruitland Formation
Type of trap:	Stratigraphic
Number of producing wells:	12 (1994)
Initial Production:	1,002 MCFGD
Cumulative Production:	1,478,106 MCFG (1994)
Gas characteristics:	1,177 BTU
Average net pay:	20 feet average
Porosity:	8-15%
Permeability:	NA

Los Pinos Fruitland, North

Location of discovery well:	NE ¼, NE ¼, sec 18, T32N, R7W (1953)
Producing formation:	Cretaceous Fruitland Formation
Type of trap:	Stratigraphic
Number of producing wells:	8 (1994)
Initial Production:	1,310 MCFGD
Cumulative Production:	2,111,682 MCFG (1994)
Gas characteristics:	1,071 BTU
Type of drive:	Gas expansion
Average net pay:	50 feet average
Porosity:	12-14% estimated
Permeability:	NA

Los Pinos Fruitland, South

Location of discovery well:	NE ¼, NE ¼, sec 17, T31N, R7W (1953)
Producing formation:	Cretaceous Fruitland Formation
Type of trap:	Stratigraphic, enhanced by fractures
Number of producing wells:	1 (1994)
Initial Production:	1,790 MCFGD
Cumulative Production:	947,221 MCFG (1994)
Gas characteristics:	980 BTU
Type of drive:	Gas expansion
Average net pay:	41 feet average
Porosity:	11.9% estimated
Permeability:	0.96 md

(Fassett, 1978,1983; Lay, 1997)

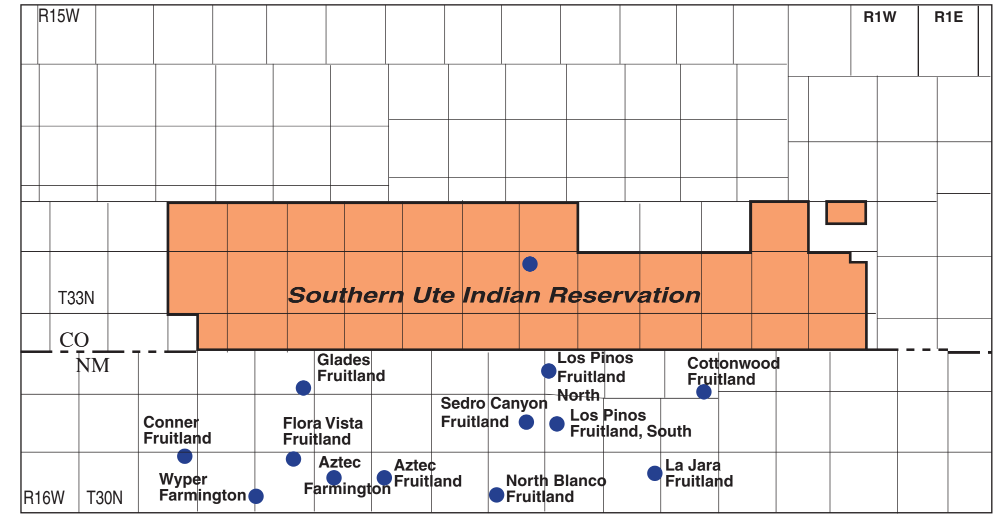

Figure SU-46. Location of discovery wells for fields that produce from the Fruitland-Kirtland Fluvial Sandstone Gas Play in and near the Southern Ute Indian Reservation.

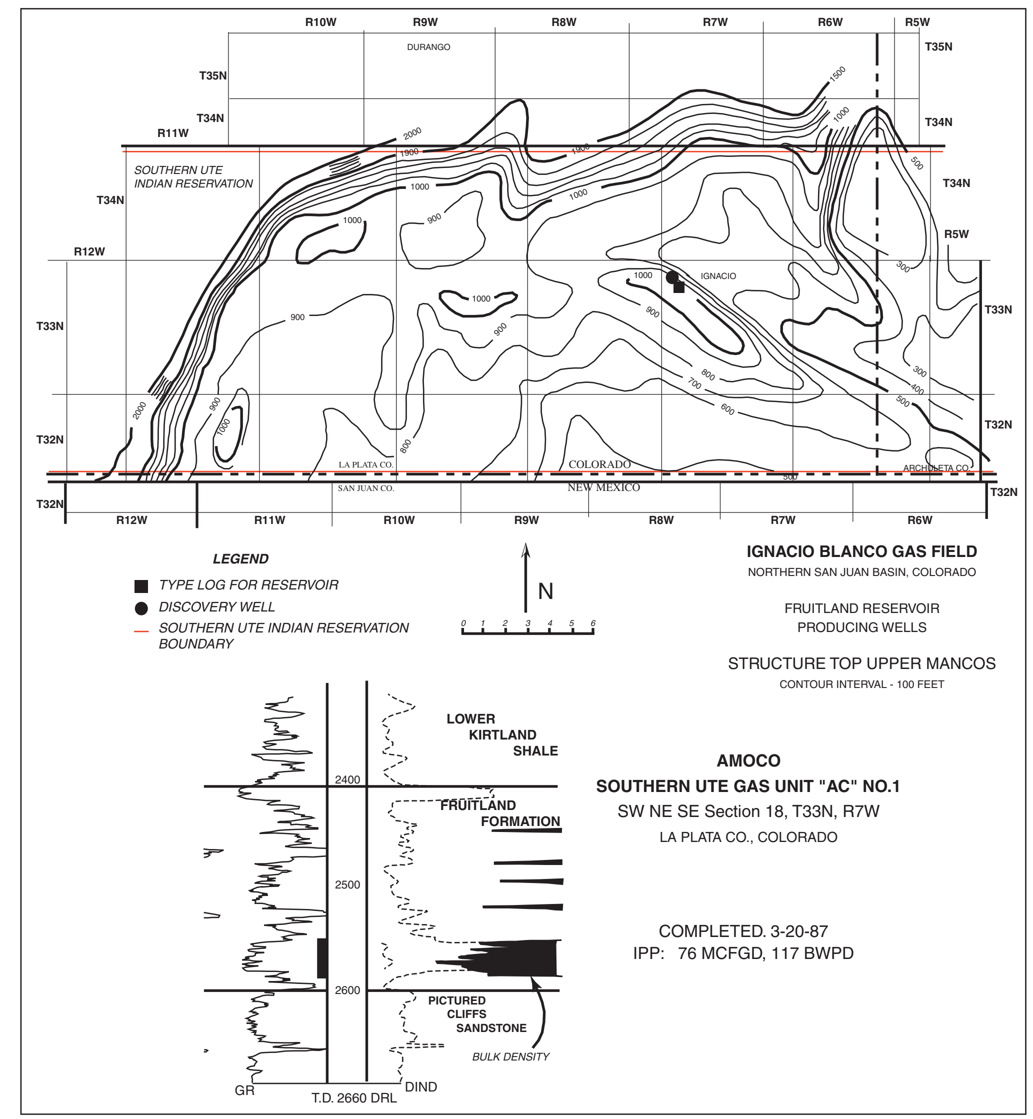

Figure SU-47. Structure contour map and log for the Ignacio Blanco gas field. Structure contours are drawn on the top of the upper Mancos Shale, contour interval is 100 feet. (modified after Harr, 1988).

Dakota Central Basin Gas Play

(USGS 2205)

General Characteristics: The Dakota Central Basin unconventional continuous-type play is contained in coastal marine barrier-bar sandstone and continental fluvial sandstone units, primarily within the Dakota Sandstone.

Reservoirs: Reservoir quality is highly variable. Most of the marine sandstone reservoirs within the basin are considered tight, in that porosities range from 5 to 15 percent and permeabilities from 0.1 to 0.25 md. Fracturing, both natural and induced, is essential for effective field development.

Source rocks: Quality of source beds for oil and gas is also variable. Non-associated gas in the Dakota pool of the Basin field was generated during late mature and postmature stages and probably had a marine Mancos Shale source (Rice, 1988).

Timing and migration: In the northern part of the central San Juan Basin, the Dakota Sandstone and Mancos Shale entered the oil generation window in Eocene time and were elevated to temperatures appropriate for the generation of dry gas by late Oligocene time. Along the southern margin of the central basin, the Dakota and lower Mancos entered the thermal zone of oil generation during the late Miocene. It is not known at what point hydrodynamic forces reached sufficient strength to act as a trapping mechanism, but early Miocene time is likely for the establishment of the present-day uplift and erosion pattern throughout most of the basin. Migration of oil in the Dakota was still taking place in the late Miocene, or even more recently, in the southern part of the San Juan Basin.

Traps: The Dakota gas accumulation is on the flanks and bottom of a large depression and is not localized by structural trapping. The fluid transmissibility characteristics of Dakota sandstones are generally consistent from the central basin to the outcrop. Hydrodynamic forces, acting in a basinward direction, have been suggested as the trapping mechanism, but these forces are still poorly understood. The seal is commonly provided by either marine shale or paludal carbonaceous shale and coal. Production is primarily at depths ranging from 6,500 to 7,500 ft.

Exploration status and resource potential: The Dakota discovery well in the central basin was drilled in 1947 southeast of Farmington, New Mexico, and the Basin field, containing the Dakota gas pool, was formed February 1, 1961 by combining several existing fields. By the end of 1993 it had produced over 4.0 TCFG and 38 MMB condensate. Almost all of the Dakota interval in the central part of the basin is saturated with gas, and additional future gas discoveries within the Basin field and around its margins are probable. (Gautier et al. 1996)

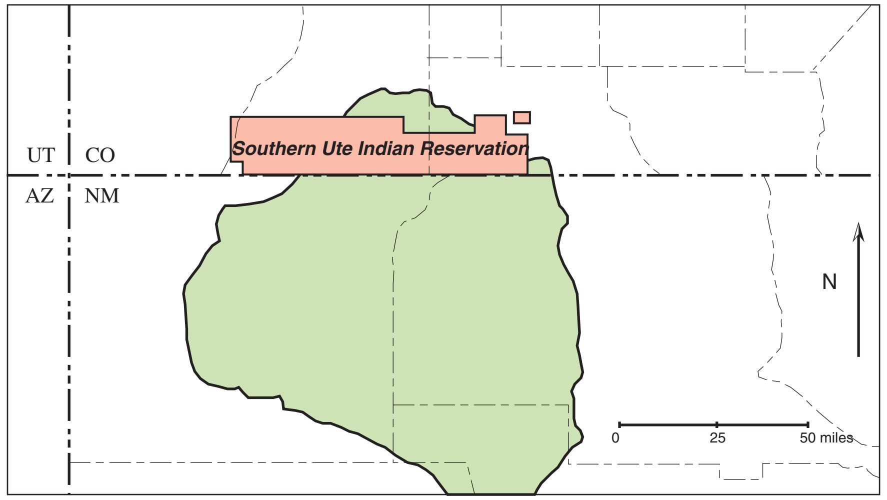

Figure SU-49. Location of the Dakota Central Basin Gas Play (modified after Gautier et al., 1996).

Analog Fields In and Near Reservation

(* field lies within the reservation boundaries)

*** Ignacio Blanco Dakota (see figure SU-50)**

Location of discovery well:	SE, NE, sec 18, T33N, R7W (1950)
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Stratigraphic and Structural
Number of producing wells:	193 (1992)
Initial production:	3,780 MCFGD
Cumulative Production:	219,443,282 MCFG (1992)
Gas characteristics:	BTU 950-990
Type of drive:	Gas expansion, possible water drive
Average net pay:	Variable 10-60 feet
Porosity:	7.5% ave.
Permeability:	0.02-0.7 md intergranular and natural fracturing

Ute Dome Dakota

Location of discovery well:	SE, sec 35, T32N, R14W (1921)
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Faulted anticline
Number of producing wells:	14 (1978)
Initial production:	12,000 MCFGD
Cumulative Production:	18,767,726 MCFG (1994)
Gas characteristics:	Sweet, BTU 1000+
Type of drive:	Combination water and volumetric
Average net pay:	30 feet
Porosity:	15%
Permeability:	10 md

(Fassett, 1978,1983; Well and Lay, 1997)

Barker Creek Dakota

Location of discovery well:	SE, NE, sec 16, T32N, R19W (1925)
Producing formation:	Upper Cretaceous Dakota
Type of trap:	Structural
Number of producing wells:	5 (1977)
Initial production:	Estimated 10,000-30,000 MCFGD
Cumulative Production:	22,542,303 MCFG (1994)
Gas characteristics:	Sweet gas, 1,125 BTU
Type of drive:	Gas expansion
Average net pay:	40 feet
Porosity:	14%
Permeability:	0-1500 md, 16.5 md ave.

Strait Canyon Dakota

Location of discovery well:	NW, SW, sec 14, T31N, R16W (1975)
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Structural
Number of producing wells:	N/A
Initial production:	303 MCFGD
Cumulative Production:	114,155 MCFG (1994)
Gas characteristics:	BTU 1031.0
Type of drive:	Water
Average net pay:	12 feet
Porosity:	15%
Permeability:	0.66-17 md, 10 md avg.

***Red Mesa**
(poor historical data)

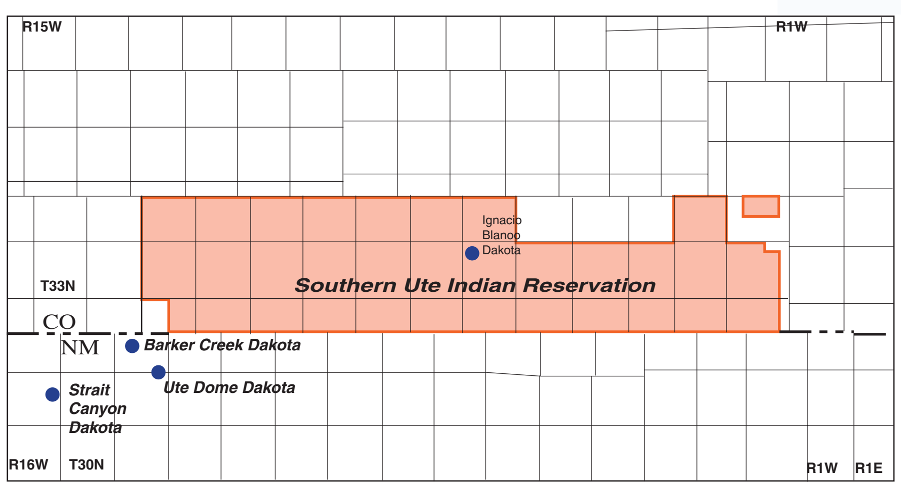

Figure SU-48. Location of discovery wells for fields producing from the Dakota Central Basin Gas Play.

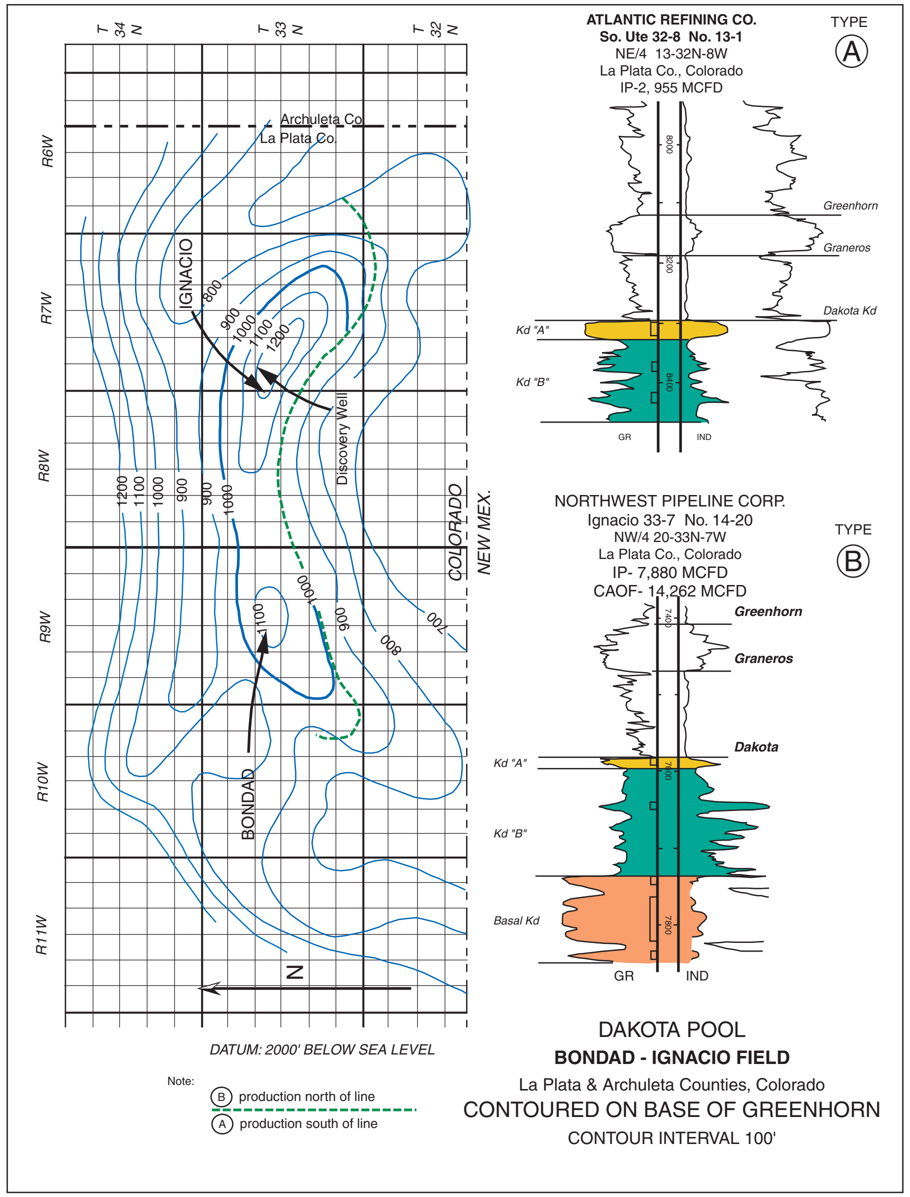

Figure SU-50. Structure map and logs for the Ignacio Blanco Gas Field. Structure Contours are drawn on the base of the Greenhorn. Kd "A" is littoral marine sandstones while Kd "B" is paludal-fluvial sandstones (modified after Bowman, 1978).